

**Grays Harbor Energy LLC
Satsop Combustion Turbine Project
Best Available Control Technology Analysis – August 2005**

INTRODUCTION

The Grays Harbor Energy LLC's Satsop Combustion Turbine (CT) Project is a partially-constructed combined-cycle natural gas-fired power generation facility located within the Satsop Development Park near Elma, Washington. The Satsop CT Project is rated at 530 MW, nominal net output (650 MW, peak).

The partially constructed project is comprised of the following equipment:

- Two General Electric GE 7FA, gas combustion turbines (maximum fuel consumption rating of 1,671 million British thermal units per hour (mmBtu/hr)) connected to an electrical generator rated at 170 MW, nominal gross output;
- One heat recovery steam generator (HRSG) and supplementary duct burner per turbine (maximum fuel consumption rating of 505 mmBtu/hr);
- One steam turbine-generator unit powered by steam produced in the HRSGs rated at 300 MW, nominal gross output;
- One auxiliary boiler rated at 25,000 pounds steam per hour;
- One 9 cell forced draft/evaporative cooling tower;
- One emergency diesel engine generator; and
- One diesel engine fire water pump.

All combustion equipment except the diesel fueled emergency generator and fire water pumps are fueled by pipeline natural gas. The diesel fuel proposed for use in the diesel engines is on-road specification diesel with less than 0.05% sulfur by weight.

The generation facility operates with filtered air being compressed in the compressor stage of each turbine and then mixed with natural gas which is burned in the combustion chambers of each turbine. Exhaust gas from the combustion chambers is expanded through power turbines to recover energy released from combustion to run the compressor section of the turbine and to directly power an electric generator. Heat in the turbine exhaust is recovered in the HRSG. When additional electrical production capacity is required, the turbine exhaust can be heated further by the duct burner, providing additional heat energy to the HRSG to make additional steam. Steam from the HRSG is used to power the steam turbine connected to an electric generator. This arrangement of combustion turbine, steam generation, and steam turbine is known as a combined-cycle gas turbine (CGT).

Excess heat in the HRSG water exhausting from the steam turbine is removed by the cooling towers. The auxiliary boiler steam is for preheating combined cycle components during startup and to initially provide sealing steam for the steam turbines. The emergency generators are used to help power down equipment, provide standby emergency lighting and control power and maintain operation of lubricating pumps in the event of a system power outage. The diesel fire water pump is for fire suppression use if the electrical power system is down.

Grays Harbor Energy LLC proposes to continue to control nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC) emissions from the gas turbines and heat recovery steam generators by the use of Dry Low-NO_x (DLN) combustors in combination with Selective Catalytic Reduction (SCR). Burning natural gas as fuel will control particulate matter, sulfur dioxide, and sulfuric acid mist to low levels.

The purpose of this Best Available Control Technology (BACT) analysis is to determine the current level of pollution control for similar combined cycle natural gas-fired power generation facilities to support an extension request for the current PSD permit. This analysis will confirm that no significant state-of-the-art advancement in BACT has occurred since the last BACT submittal and that the emission limits and control technologies in the current permit are consistent with recent BACT determinations.

BACT TOP-DOWN ANALYSIS METHODOLOGY

Criteria air pollutant emissions from the Satsop CT Project will include NO₂, SO₂, PM, CO, and VOCs. The technologies available for controlling these emissions are discussed in this section. A “top-down” BACT analysis approach has been used to evaluate BACT for the Satsop CT Project.

The five steps of a typical “top-down” BACT process consist of the following:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies
4. Evaluate the most effective control technology
5. Select BACT

A brief description of each step is presented below.

Step 1 - Identify All Control Technologies

The first step in a “top-down” BACT analysis is to identify all available control options. Air pollution controls include available technologies, methods, systems, and techniques for control of the regulated pollutant, as well as alternate production processes that may reduce the generation of pollutants. The control alternatives should not only include existing controls for the source category or piece of equipment in question, but also innovative technologies and controls applied to similar source categories.

Step 2 - Eliminate Technically Infeasible Options

In the second step of the “top-down” BACT evaluation, the technical feasibility of the control options identified in Step 1 are evaluated with respect to source-specific factors. The list of technically infeasible control options must be clearly documented. The applicant must demonstrate that, based on physical, chemical, and/or engineering principles, technical difficulties will preclude the successful use of the control option. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 - Rank Remaining Control Technologies

In Step 3, all remaining control alternatives not eliminated in Step 2 are ranked in order of control effectiveness for the pollutants under review. The most effective control alternative is ranked at the top. A list of control alternatives is prepared for each pollutant and for each emission unit subject to the BACT analysis. The list presents the array of control technology alternatives and includes the following types of information:

- Range of control efficiencies (percentage of pollutant removed)
- Expected emission rate (tons per year, pounds per year)
- Expected removal efficiency at the Satsop CT Project (tons per year)
- Economic impacts (cost effectiveness)
- Environmental impacts (includes significant or unusual impacts on other media, water or solid waste)
- Energy impacts

A detailed analysis of costs and other impacts is not required if the applicant chooses the most stringent emissions control technology. The applicant must document that the control option is the most stringent alternative and briefly explain the environmental impacts.

Step 4 - Evaluate Most Effective Control Technology

After the available and technically feasible control technology options have been identified, potential impacts such as energy, environmental, and economic impacts are considered to determine the best available level of control (Step 4). For each control option, the applicant must present an objective evaluation of each impact. Both beneficial and adverse impacts are described and, where possible, quantified. In general, BACT analyses focus on the direct impact of the control alternative.

In this analysis, the technology with the highest control efficiency is evaluated first. If this technology is found to have no adverse environmental, energy, or economic impacts, it is selected as BACT and no further analysis is necessary. If the most stringent technology is shown to be inappropriate because of energy, environmental, or economic reasons, the applicant must fully document the rationale for this conclusion. Then, the next most effective control alternative on the list becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated due to potential source-specific reasoning.

Step 5 - Select BACT

The most effective control option not eliminated in Step 4 is proposed as BACT for the pollutant(s) and emission unit(s) under review.

COMBUSTION TURBINES

The EPA maintains a database of technologies that have been implemented as Reasonably Achievable Control Technology (RACT), BACT, or Lowest Achievable Emission Rate (LAER) (known as the RACT/BACT/LAER Clearinghouse or RBLC database). This database was accessed to identify control strategies implemented to date on turbines. The RBLC was searched for all turbines greater than 25 MW where permits or latest updates were made after January 1, 2002. From the initial search results, the data set was further reduced by eliminating simple cycle turbine configurations and turbines rated less than 90 MW. Also, sources known, but not found in the RBLC, are included. Table 1 presents a summary of power generation projects comparable to the Satsop CT Project.

Table 1
Recent Power Generation Projects

Facility	Location	EPA Region	Permit Date or Last Update	Size	
Bluewater Energy Center LLC	St. Clair County, MI	5	01/23/2004	180	MW
BP Cherry Point Cogeneration	Skagit County, WA	10	12/21/2004	720	MW (Total)
Chehalis Generation Facility	Chehalis, WA	10	Operational	520	MW (Total)
COB Energy Facility, LLC	Klamath County, OR	10	06/21/2004	1150	MW (Total)
CPV Warren LLC	Warren County, VA	3	03/08/2005	180	MW
Duke Energy Arlington Valley (AVEFII)	Maricopa County, AZ	9	01/29/2004	325	MW
Duke Energy Hanging Rock Energy Facility	Lawrence County, OH	5	07/05/2005	172	MW
Duke Energy Washington County LLC	Washington County, OH	5	07/05/2005	170	MW
Duke Energy Wythe LLC	Wythe County, VA	3	03/25/2004	170	MW
El Dorado Energy, LLC	Clark County, NV	9	09/15/2004	165	MW
Fairbault Energy Park	Rice County, MN	5	09/21/2004	187	MW
Florida Power & Light Manatee Plant	Manatee County, FL	4	01/05/2004	170	MW
Florida Power & Light Martin Plant	Martin County, FL	4	12/22/2003	170	MW
Forsyth Energy Plant	Forsyth County, NC	4	09/17/2004	1844	MMBtu/hr
Hines Energy Complex	Polk County, FL	4	11/06/2003	170	MW
James City Energy Park	James City County, VA	3	03/29/2004	170	MW
Kalkaska Generating LLC	Kalkaska County, MI	5	01/16/2004	605	MW (Total)
Klamath Generation, LLC	Klamath County, OR	10	03/26/2004	480	MW
Mankato Energy Center	Blue Earth County, MN	5	02/08/2005	630	MW (Total)
McIntosh Combined Cycle Facility	Effingham County, GA	4	01/24/2005	140	MW
Mint Farm Generation	Lewis County, WA	10	09/16/2004	319	MW
Mirant Wyandotte LLC	Wayne County, MI	5	01/30/2004	2200	MMBtu/hr
Reliant Energy Choctaw County, LLC	Choctaw County, MS	4	01/25/2005	230	MW
Sacramento MUD	Sacramento County, CA	9	03/09/2004	1611	MMBtu/hr
Salt River Project/Santan Gen. Plant	Maricopa County, AZ	9	05/24/2005	175	MW
South Shore Power LLC	Berrien County, MI	5	01/23/2004	172	MW
Sumas 2 Generation Facility	Whatcom County, WA	10	01/21/2005	660	MW (Total)
Walla Power Project	Walla Walla County, WA	10	11/21/2003	1300	MW (Total)

Nitrogen Oxides

The formation of nitrogen oxides is the result of thermal oxidation of diatomic nitrogen in the combustion chamber. The rate of formation is dependent upon combustion temperature, residence time of combustion products at high temperatures, and the availability of oxygen in the flame zone of a combustion turbine generator. This section addresses the available control alternatives for NO_x emissions.

Available Control Technologies

Control technologies for NO_x emissions can be classified as combustion modifications or post-combustion controls. Table 2 presents a summary of NO_x control technologies for combined cycle combustion turbines similar to the Satsop CT Project.

Table 2
Pollution Control For NO_x – Combustion Turbines

Facility	Emissions	Pollution Control	Basis
Bluewater Energy Center LLC	4.5 ppm	DLN; SCR	BACT-PSD
BP Cherry Point Cogeneration		DLN; SCR	
Chehalis Generation Facility		DLN; SCR	
COB Energy Facility, LLC	2.5 ppm	DLN; SCR	BACT-PSD
CPV Warren LLC	2.0 ppm	Two-Stage Lean Pre-mix DLN Combustion and SCR	BACT-PSD
Duke Energy Arlington Valley (AVEFII)	2.0 ppm	SCR	BACT-PSD
Duke Energy Hanging Rock Energy Facility	3.0 ppm	DLN; SCR	BACT-PSD
Duke Energy Washington County LLC	3.5 ppm	DLN; SCR	BACT-PSD
Duke Energy Wythe LLC	2.5 ppm	DLN; SCR	BACT-PSD
El Dorado Energy, LLC	3.7 ppm	Low NO _x Burner; SCR	BACT-PSD
Fairbault Energy Park	3.0 ppm	DLN; SCR	BACT-PSD
Florida Power & Light Manatee Plant	2.5 ppm	DLN; SCR	BACT-PSD
Florida Power & Light Martin Plant	2.5 ppm	DLN; SCR	BACT-PSD
Forsyth Energy Plant	3.5 ppm	DLN; SCR	BACT-PSD
Hines Energy Complex	2.5 ppm	DLN; SCR	BACT-PSD
James City Energy Park	2.5 ppm	DLN; SCR	BACT-PSD
Kalkaska Generating LLC	3.0 ppm	DLN; SCR	BACT-PSD
Klamath Generation, LLC	2.5 ppm	DLN; SCR	BACT-PSD
Mankato Energy Center	3.0 ppm	Lean Pre-mix Combustion and SCR	BACT-PSD
McIntosh Combined Cycle Facility	2.5 ppm	DLN; SCR	BACT-PSD
Mint Farm Generation	2.5 ppm	DLN; SCR	
Mirant Wyandotte LLC	3.5 ppm	DLN; SCR	BACT-PSD
Reliant Energy Choctaw County, LLC	3.5 ppm	SCR	BACT-PSD
Sacramento MUD	2.0 ppm	SCR	LAER
Salt River Project/Santan Gen. Plant	2.0 ppm	SCR	LAER
South Shore Power LLC	3.0 ppm	DLN; SCR	BACT-PSD
Sumas 2 Generation Facility	2.0 ppm	DLN; SCR	BACT-PSD
Wallula Power Project	2.5 ppm	SCR	Other – Case by Case

While all of the projects similar to the Satsop CT Project are employing dry-low NO_x (DLN) and/or selective catalytic reduction (SCR) technologies, two additional NO_x control technologies are often discussed even though these other technologies have not been proven technically feasible for GE 7FA combustion turbines or others of similar size: SCONO_xTM(EM_xTM) and Xonon Cool Combustion[®]. Other NO_x control technologies such as water or steam injection are not applicable to this project as fuel oil is not being proposed for use in the turbines and control efficiencies are less than other technologies considered.

The available NO_x control technologies for natural gas-fired combustion turbines are briefly described below.

Combustion Modifications:

- **Dry Low-NO_x Combustor:** The modern, dry low-NO_x (DLN) combustor is typically a three-staged, lean, premixed design, which utilizes a central diffusion flame for stabilization. The lean, premixed approach burns a lean fuel-to-air mixture for a lower combustion flame temperature resulting in lower thermal NO_x formation. The combustor operates with one of the lean premixed stages and the diffusion pilot at lower loads and the other stages at higher loads. This provides efficient combustion at lower temperatures, throughout the combustor-loading regime. The dry low-NO_x combustor reduces NO_x emissions by up to approximately 87 percent over a conventional combustor.
- **Xonon Cool Combustion[®]:** Catalytica Energy Systems' Xonon Cool Combustion[®] system improves the combustion process by lowering the peak combustion temperature to reduce the formation of NO_x while also providing further control of CO and unburned hydrocarbon emissions that other NO_x control technologies (such as water injection and DLN) cannot provide. Most gas turbine emission control technologies remove air contaminants from exhaust gas prior to release to the atmosphere. In contrast, the overall combustion process in the Xonon system is a partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. In the catalyst module, a portion of the fuel is combusted without a flame (i.e., at relatively low temperature) to produce a hot gas. A homogeneous combustion region is located immediately downstream where the remainder of the fuel is combusted.

The key feature of the Xonon combustion system is a proprietary catalytic component, called the Xonon Module, which is integral to the gas turbine combustor. Xonon combusts the fuel without a flame, thus eliminating the peak flame temperatures that lead to NO_x formation. Turbine performance is not affected.

Xonon is an innovative technology that has been commercialized on smaller-scale projects with support from the U.S. Department of Energy, the California Energy Commission (CEC), and the California Air Resources Board (CARB). A pilot effort in Santa Clara, California used a Xonon system on a 1.4 MW simple cycle facility. CARB stated in its June 1999 report that "Emission levels from 1.33 to 4.04 ppmvd NO_x at 15 percent oxygen (O₂) have been achieved at Silicon Valley Power utilizing the Xonon technology" (CARB 1999). However, it further indicated that "there is not sufficient operating experience to ensure reliable performance on large gas turbines." More

recently, Catalytica Energy Systems' advertises the operation of a Xonon-equipped 1.4 MW Kawasaki M1A-13X gas turbine at the Sonoma Developmental Center in Eldridge, California. Catalytica Energy Systems' states, "the unit has been operating on a 24 / 7 basis, with NO_x emissions consistently and substantially below its 3 parts per million (ppm) guarantee." This installation has been operating since November 2002.

Xonon does not currently represent an available control technology for any large turbine. While a joint venture agreement was in place with General Electric (GE) to eventually develop Xonon as original equipment manufacturer and retrofit equipment for the entire GE turbine line, GE does not currently offer a Xonon combustor option for 7FA or any other large industrial turbine. An Application for Certification approved by CEC for the Pastoria Energy Facility Project (December 20, 2000) proposed to install Xonon on F-Class Turbines, however, Xonon was determined not to be technically feasible and the plant was constructed using DLN burners and SCR. The NO_x emission limit proposed for the Pastoria Project was being evaluated under LAER criteria. DLN/SCR was proposed as the back-up control technology in the event that the Xonon technology proved infeasible. Currently Catalytica Energy Systems is only marketing Xonon technology for gas turbines within the 1 to 15 MW size range. Hence, at this time, Xonon does not represent a currently available control technology for the Satsop CT Project. Furthermore, the Xonon system is only guaranteeing 3 ppm for a NO_x emission rate, whereas the Satsop CT Project currently has 2.5 ppm 1-hr and 2.0 ppm 24-hr emission limits for NO_x.

Post-Combustion Controls:

- **Selective Catalytic Reduction:** In the SCR process, a reducing agent, such as aqueous ammonia, is introduced into the turbine's exhaust, upstream of a metal or ceramic catalyst. As the exhaust gas mixture passes through the catalyst bed, the reducing agent selectively reduces the nitrogen oxide compounds present in the exhaust to produce elemental nitrogen (N₂) and water (H₂O). Ammonia is the most commonly used reducing agent. Adequate mixing of ammonia in the exhaust gas and control of the amount of ammonia injected (based on the inlet NO_x concentration) are critical to obtaining the required reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum O₂ concentrations and remain within a specified temperature range (typically between 580°F and 650°F), with the range dictated by the type of catalyst. Exhaust gas temperatures greater than the upper limit (850°F) will pass the NO_x and unreacted ammonia through the catalyst. The most widely used catalysts are vanadium, platinum, titanium, or zeolite compounds impregnated on metallic or ceramic substrates in a plate of honeycomb configuration. The catalyst life expectancy is typically 3 to 6 years, at which time the vendor can recycle the catalyst to minimize waste.

The SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical "poisoning". Principal poisons include arsenic, sulfur, potassium, sodium, and calcium.

One concern when using the SCR catalyst on fuels containing sulfur is the oxidation of flue gas SO_2 to SO_3 which will then combine with H_2O vapor to form H_2SO_4 . Accordingly, corrosion of downstream piping and heat transfer equipment (which will operate at temperatures below the H_2SO_4 dew point) will be of concern when using SCR with sulfur-bearing fuels. Also, SO_3 will combine with unreacted ammonia to form ammonium bisulfate and ammonium sulfate. Ammonium bisulfate is a hygroscopic solid at approximately 300°F and can deposit on equipment surfaces below this temperature as a white solid. Both ammonium bisulfate and ammonium sulfate will be expected to deposit on HRSG heat transfer equipment when temperatures below 300°F occur. Because ammonium bisulfate is hygroscopic, the material will absorb H_2O , forming a sticky substance which can cause fouling of heat transfer equipment. Ammonium bisulfate cannot be easily removed due to its sticky nature; a unit shutdown will be required to clean fouled equipment. Problems associated with ammonium salt deposition can be ameliorated, to some extent, by reducing the ammonia/ NO_x molar ratio when firing sulfur-containing fuels.

NO_x emissions as low as 2.0 ppmvd have been permitted using SCR in conjunction with dry low- NO_x combustors. The combination of dry low- NO_x combustors with the SCR ranks as the most efficient and proven combination of control technologies. This is the technology currently permitted for the Satsop CT Project.

- **SCONO_xTM(EMxTM):** SCONO_xTM(EMxTM) is a developing technology aimed at post-combustion control of multiple pollutants. The SCONO_xTM system is being produced by EmeraChem, LLC (formerly Goal Line Environmental Technologies) and is now called EMxTM. The EMxTM system uses a coated oxidation catalyst installed in the flue gas to remove both NO_x and CO without a reagent such as ammonia. The NO emissions are oxidized to NO_2 and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to de-absorb the NO_2 from the catalyst and reduce it to N_2 prior to exit from the stack. CO is oxidized to CO_2 , while VOCs are oxidized to CO_2 and water, before exiting the stack.

EMxTM prefers an operating temperature range between 500°F and 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, NO_2 is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regeneration gas consists of steam, carbon dioxide, and a dilute concentration of hydrogen. The regeneration gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. At any one time, four oxidation/absorption cycles are occurring and one regeneration cycle is occurring.

Commercial operation of EMx™ began with an installation at the Sunlaw Federal Plant in Vernon, California in December 1996. The Federal Plant is owned by Sunlaw Cogeneration Partners (a part owner in Goal Line) and consists of an LM2500 combustion turbine (approximately 28 MW) with a HRSG. The unit is roughly one-eighth the size of the proposed GE 7FA combustion turbines.

The EMx™ system has also been installed on two 5-MW Solar Taurus combustion turbines at the Wyeth BioPharma (formerly Genetics Institute) cogeneration facility in Andover, MA. While this facility experienced prolonged performance problems trying to achieve the 2.5 ppm NO_x permit limit on the first combustion turbine, a second combustion turbine was constructed with the EMx™ system in 2003. While EmeraChem states that “actual values on gas [are] typically below 1.5 ppm, with substantial periods below 1.0 ppm.”, the reference doesn’t provide data on the number of exceedances of the permit limit. It has been reported that other installations have had trouble meeting the 2.5 ppm NO_x limit as well. Furthermore, the largest installation to date has been on an Alstom Power 43-MW GTX-100 turbine in Redding, California.

Several years ago ABB Alstom and the former Goal Line Technologies representatives entered into an agreement to make EMx™ commercially available for an F-Class ABB turbine at a guaranteed emissions level of 2.5 ppmvd NO_x (at 15 percent O₂). To date, EMx™ has not been placed on an F-Class turbine.

The La Paloma Generating Project in California initially proposed to demonstrate the viability of EMx™ on one ABB KA-24 (150 MW) turbine at that facility, assuming that the technological and commercial availability issues could be resolved. The NO_x emission limit to be met by either EMx™ or DLN/SCR was approved under LAER criteria. Commercial, warranty, and operational issues of concern for EMx™ were not resolved by the final engineering design deadline.

Otay Mesa Generating Company LLC, an affiliate of Umatilla Generating Company, LP, submitted an Application for Certification to the CEC for the Otay Mesa Project on August 2, 1999, which proposed to install EMx™ anticipating that commercial, warranty, and operational issues of concern may be resolved in time for that facility’s construction. The NO_x emission limit proposed for the Otay Mesa Project was evaluated under LAER criteria. DLN/SCR was proposed as the back-up control technology if the EMx™ technology proves infeasible for this project. Ultimately, EMx™ was determined not to be technically feasible and the plant was constructed using Dry Low NO_x burners with SCR.

Other challenges in implementing EMx™ for large turbine projects such as the Satsop CT Project involve pressure drop concerns and sulfur sensitivity problems. The pressure drop caused by the EMx™ system is twice that of a SCR system, according to GE Power Generation. Also, they state that EMx™ is very sensitive to sulfur. In parts of the Pacific Northwest, the sulfur content in the pipeline natural gas is higher than many other places across the country. Therefore, regardless of the turbine size concern, EMx™ may be more experimental than proven at this time for facilities supplied by the higher sulfur

natural gas. Furthermore, an emissions guarantee of less than 2.0 ppm NO_x is not available. The Satsop CT Project currently has 2.5 ppm 1-hr and 2.0 ppm 24-hr emission limits for NO_x. Consequently, EMx™ is not considered a technically feasible technology at this time for the Satsop CT Project.

Selected BACT

Although there can be adverse effects using SCR control technology, previous BACT determinations in Washington state indicate that SCR is required to reduce NO_x emissions to levels of 2.0 ppmvd. The Satsop CT Project is located in an attainment area for ozone, and the implementation of this technology should not significantly contribute to ozone levels. Using a combination of the most advanced dry low-NO_x combustor technology with SCR control technology can provide a significant amount of NO_x reduction to a level of 2.0 ppmvd at 15 percent O₂. The proposed NO_x emission limits, as contained in the current permit, are shown in Table 3, and represent current BACT. As the most stringent emission limits and controls are being proposed as BACT, an economic analysis is not required.

Table 3
Proposed BACT NO_x Emission Limits ^(a)

Pollutant	Emissions (ppmvd) at 15% O₂	Emissions (lb/hr)
NO _x	2.0 (24-hr moving average)	17.4
	2.5 (1-hr average)	21.7

^(a)These emission limits apply to CT loads ≥ 50%.

Sulfur Dioxide

SO₂ emissions from gas turbines are a function of the sulfur content of the fuel, with virtually all fuel sulfur converted to SO₂. Coal generally has the highest sulfur content, followed by crude oils, sewage gas, waste fuels, and refined fuel oils (including No. 2). Usually, natural gas has only trace amounts of sulfur, thus the control applications discussed below are generally not applicable with only natural gas fueled CT technology. This section describes available control equipment and the BACT analysis for sulfur dioxide.

Available Control Technologies

Table 4 summarizes the pollution control technologies for SO₂. Other technically feasible control technologies are two typical flue gas desulfurization processes: wet and dry scrubbing. These control technologies are described below.

Table 4
Pollution Control For SO₂ – Combustion Turbines

Facility	Emissions	Pollution Control	Basis
Bluewater Energy Center LLC	177.0 tpy 0.008 gr S/scf	Natural Gas and Good Combustion Techniques	BACT-PSD
BP Cherry Point Cogeneration	8.8 lb/hr	Natural Gas Fuel	BACT-PSD
Chehalis Generation Facility	10.4 lb/hr		
COB Energy Facility, LLC	No Value	Low Sulfur Fuel 0.8 gr /100 scf	N/A
Duke Energy Hanging Rock Energy Facility	14.4 lb/hr	Natural Gas - 2 gr S/100 scf	BACT-PSD
Duke Energy Washington County LLC	14.5 lb/hr	Natural Gas - 2 gr S/100 scf	BACT-PSD
Duke Energy Wythe LLC	2.08 lb/hr	Good Combustion Practices and Natural Gas 0.3 gr /100 scf	BACT-PSD
El Dorado Energy, LLC	1.03 lb/hr	No Control Specified	Other - Case by Case
Fairbault Energy Park	0.8 gr /100 scf	Low Sulfur Fuel 0.8 gr /100 scf	BACT-PSD
Florida Power & Light Manatee Plant	No Value	Clean Fuels - 2 gr S/100 scf	BACT-PSD
Florida Power & Light Martin Plant	No Value	Clean Fuels - 2 gr S/100 scf	BACT-PSD
Forsyth Energy Plant	0.0006 lb/MMBtu	Very Low Sulfur Fuel	BACT-PSD
Hines Energy Complex	No Value	Low Sulfur Fuels	BACT-PSD
James City Energy Park	11.3 lb/hr	Low Sulfur Fuels	BACT-PSD
Kalkaska Generating LLC	5.2 lb/hr	Low Sulfur Fuels – Ave. 0.75 gr S/100 scf	BACT-PSD
Klamath Generation, LLC	No Value	Low Sulfur Fuels	BACT-PSD
Mankato Energy Center	0.8 gr /100 scf	Low Sulfur Fuel 0.8 gr /100 scf	BACT-PSD
Mint Farm Generation	20.7 lb/hr	Low Sulfur Fuel and Good Combustion Practices	
Mirant Wyandotte LLC	53.4 tpy	Natural Gas - 0.8 gr /100 scf	BACT-PSD
Reliant Energy Choctaw County, LLC	1.38 lb/hr	No Control Specified	BACT-PSD
Sacramento MUD	1.0 gr/100scf	Low Sulfur Natural Gas	LAER
South Shore Power LLC	0.2 gr/100scf	Low Sulfur Natural Gas	BACT-PSD
Sumas 2 Generation Facility	1 ppm	Low Sulfur Fuel	BACT-PSD
Wallula Power Project	0.35 ppm	Low Sulfur Natural Gas	Other - Case by Case

- Wet Scrubbing:** In this process, the exhaust gas is passed through a spray tower scrubber. Wet scrubbing devices work on the principle of reacting a liquid-phase reagent with the SO₂ in the exhaust stream to form various end products (depending on the type of reagent used). Optimum process temperatures are approximately 100°F to 140°F. Thus, some type of gas cooling is usually required upstream of the spray tower scrubber. Because some of the slurry is entrained by the gas as small droplets, the exhaust stream leaving the scrubber is normally passed through a mist eliminator to remove the droplets and return them to the scrubber. The exhaust gas is then directed to a stack.

Limestone is the most frequently used reagent in wet scrubbing systems as the cost is much less than that of either lime or sodium carbonate. Wet scrubbing devices are predominately used in large generators of SO₂ such as coal-fired boiler facilities as well as some chemical plants and kraft pulp mills.

- **Dry Scrubbing:** A dry scrubber removes SO₂ by mixing the flue gas with an atomized slurry in a spray dry scrubber. The water in the slurry evaporates, and the SO₂ is subsequently absorbed by the remaining fine solids. Reaction temperatures are maintained slightly above the gas dew point by controlling the amount of water in the slurry. The cleaned gases are then routed to the exhaust stack or particulate capturing/collection device.

This technology is mainly used in large generators of SO₂ such as large coal-fired utility boilers. The reagent used in these systems is usually lime since it is more readily available and cheaper than sodium carbonate.

- **Fuel Specification:** Natural gas is considered a clean fuel containing only trace amounts of sulfur (USEPA 1985b). Natural gas is the only fuel proposed for the combustion turbines.

Evaluation of Technical Feasibility

- **Wet Scrubbing:** Wet scrubbing is widely used in large coal-fired boilers, kraft pulp mill, and other large chemical processing plants. However, it has never been implemented on a natural gas-fired combustion turbine facility. Most combustion turbine facilities are small and the pressure drops imposed by wet scrubbing applications would be a severe operational constraint. An induced draft fan or similar device would be required to overcome the pressure drop in the exhaust system. This may cause CT operation problems with a fan drawing exhaust gas from the turbine and with the air/fuel ratio controls in the combustor. There is no commercial experience with exhaust gas blowers in natural gas-fired combustion turbine equipment trains. For these reasons, wet scrubbing is considered technically infeasible for this project.
- **Dry Scrubbing:** Dry scrubbing is also primarily used with large utility coal-fired boilers and has never been implemented on a natural gas-fired combustion turbine system. As with wet scrubbing, this technology would impose excessive pressure drop constraints on a combustion turbine facility. Thus, this technology is considered technically infeasible for the same reason as presented for wet scrubbers and is not evaluated any further in this BACT analysis.
- **Fuel Specification:** Natural gas fuel continues to be the only fuel proposed for the combustion turbines at the Satsop CT Project.

Selected BACT

The exclusive use of natural gas for the combustion turbines is considered BACT for controlling SO₂ emissions. The proposed control technology and SO₂ emissions for the Satsop CT Project are representative of current BACT determinations. The proposed SO₂ emission limits, as contained in the current permit, are shown in Table 5. As the most stringent emission limits and controls are being proposed as BACT, an economic analysis is not required.

Table 5
Proposed BACT SO₂ Emission Limits^(a)

Pollutant	Emissions (ppmvd) at 15% O₂	Emissions (lb/hr)
SO ₂	0.11	1.3

^(a)These emission limits apply to CT loads \geq 50%.

Carbon Monoxide and Volatile Organic Compounds

Carbon Monoxide (CO) is a product of incomplete combustion, where oxygen is not present in sufficient quantities to fully oxidize the fuel. In addition, CO emission levels are a direct function of the air/fuel ratio. Combustion inefficiencies introduced by combustion modifications for NO_x control increase the generation of CO. Volatile Organic Compound (VOC) emissions are also products of incomplete combustion. Some VOCs are involved in the process of ozone formation.

Available Control Technologies

Control technologies for CO and VOC can be classified as combustion modifications or post-combustion controls. Tables 6 and 7 list the control technologies available for the control of CO and VOC, respectively. This section describes each technology and its technical feasibility for controlling these contaminant emissions from a natural gas-fired combustion turbine.

Table 6
Pollution Control for CO - Turbines

Facility	Emissions	Pollution Control	Basis
Bluewater Energy Center LLC	8.0 ppm	Catalytic Afterburner	BACT-PSD
BP Cherry Point Cogeneration	2.0 ppm	Oxidation catalyst plus lean premix turbine burners	BACT-PSD
Chehalis Generation Facility	3.0 ppm	Oxidation Catalyst	
COB Energy Facility, LLC	2.0 ppm	Catalytic Oxidation	BACT-PSD
CPV Warren LLC	1.8 ppm	Good Combustion Practices	BACT-PSD
Duke Energy Arlington Valley (AVEFII)	3.0 ppm	Catalytic Oxidizer	BACT-PSD
Duke Energy Hanging Rock Energy Facility	9.0 ppm	No Control	BACT-PSD
Duke Energy Washington County LLC	14 ppm	No Control	BACT-PSD
Duke Energy Wythe LLC	14.6.0 ppm	Good Combustion Practices	BACT-PSD
El Dorado Energy, LLC	3.5 ppm	Oxidation Catalyst	LAER
Fairbault Energy Park	10.0 ppm	Good Combustion Practices	BACT-PSD
Florida Power & Light Manatee Plant	10.0 ppm	Good Combustion Design/Practices	BACT-PSD
Florida Power & Light Martin Plant	10.0 ppm	Good Combustion Design/Practices	BACT-PSD
Forsyth Energy Plant	25.9 ppm	Good Combustion Design/Practices	BACT-PSD
Hines Energy Complex	10.0 ppm	Good Combustion Design/Practices	BACT-PSD
James City Energy Park	12.0 ppm	Good Combustion Practices	BACT-PSD
Kalkaska Generating LLC	5.0 ppm	Oxidation Catalyst	BACT-PSD
Klamath Generation, LLC	5.0 ppm	Catalytic Oxidation	BACT-PSD
Mankato Energy Center	4.0 ppm	Catalytic Oxidation and Good Combustion Practices	BACT-PSD
McIntosh Combined Cycle Facility	2.0 ppm	Catalytic Oxidizer	BACT-PSD
Mint Farm Generation	6.0 ppm 1-hr 2.0 ppm annual	Catalytic Oxidation	
Mirant Wyandotte LLC	3.8 ppm	Catalytic Oxidation	BACT-PSD
Reliant Energy Choctaw County, LLC	18.36 ppm	SCR	BACT-PSD
Sacramento MUD	4.0 ppm	Good Combustion Control	LAER
Salt River Project/Santan Gen. Plant	3.0 ppm	Catalytic Oxidizer	LAER
South Shore Power LLC	4.0 ppm	Catalytic Oxidation and Good Combustion Practices	BACT-PSD
Sumas 2 Generation Facility	2.0 ppm	Oxidation Catalyst	BACT-PSD
Wallula Power Project	2.0 ppm	Oxidation Catalyst	Other – Case by Case

Table 7
Pollution Control for VOCs - Turbines

Facility	Emissions	Pollution Control	Basis
Bluewater Energy Center LLC	9.4 ppm	Catalytic Afterburner	BACT-PSD
BP Cherry Point Cogeneration	3.0 lb/hr	Oxidation catalyst plus lean premix turbine burners	BACT-PSD
Chehalis Generation Facility	7.0 lb/hr	Oxidation Catalyst	
COB Energy Facility, LLC	7.1 lb/hr	Catalytic Oxidation and Good Combustion Practices	BACT-PSD
CPV Warren LLC	1.0 ppm	Catalytic Oxidation and Good Combustion Practices	BACT-PSD
Duke Energy Arlington Valley (AVEFII)	4.0 ppm		BACT-PSD
Duke Energy Hanging Rock Energy Facility	20.4 lb/hr	No Control	BACT-PSD
Duke Energy Washington County LLC	19.6 lb/hr	SCR	BACT-PSD
Duke Energy Wythe LLC	21 lb/hr	Good Combustion Practices	BACT-PSD
El Dorado Energy, LLC	6.6 lb/hr	Good Combustion Practices	BACT-PSD
Fairbault Energy Park	1.0 ppm	Good Combustion Practices	BACT-PSD
Florida Power & Light Manatee Plant	1.3 ppm	Good Combustion Practices	BACT-PSD
Florida Power & Light Martin Plant	1.3 ppm	Good Combustion Practices	BACT-PSD
Forsyth Energy Plant	5.7 ppm	Good Combustion Design/Practices	BACT-PSD
Hines Energy Complex	2.0 ppm	Good Combustion Practices	BACT-PSD
James City Energy Park	4.0 ppm	Good Combustion/Design and Clean Fuel	
Kalkaska Generating LLC	3.5 ppm	Oxidation Catalyst	BACT-PSD
Klamath Generation, LLC	7.2 lb/hr	Catalytic Oxidation and Good Combustion Practices	BACT-PSD
Mankato Energy Center	34.0 ppm	Catalytic Oxidation and Good Combustion Practices	BACT-PSD
McIntosh Combined Cycle Facility	2.0 ppm	Catalytic Oxidation	BACT-PSD
Mint Farm Generation	8.9 lb/hr	Catalytic Oxidation	
Mirant Wyandotte LLC	10.0 ppm	Catalytic Oxidizer	Other – Case by Case
Reliant Energy Choctaw County, LLC	3.64 ppm	SCR	BACT-PSD
Sacramento MUD	1.4 ppm	No Control Specified	BACT
Salt River Project/Santan Gen. Plant	4.0 ppm	Catalytic Oxidizer	LAER
South Shore Power LLC	2.5 ppm	Oxidation Catalyst	BACT-PSD
Sumas 2 Generation Facility	420 lb/day	Good Combustion Practices	BACT-PSD
Wallula Power Project	5.0 ppm	Good Combustion Practices	Other – Case by Case

Combustion Modifications

The most practical approach for reducing CO and VOC emissions is maximizing the efficiency of fuel combustion by proper design, installation, operation, and maintenance of the turbine combustor. Efficient combustion reduces the amount of fuel required to generate a given amount of power, thereby decreasing the generation of CO and VOC.

- **Dry Low-NO_x Combustor:** Dry low-NO_x (DLN) combustors are designed to minimize the formation of NO_x. DLN combustors have also been able to achieve lower emissions of CO and VOCs. Vendors of DLN combustors have quoted CO emission rates of 9 ppm while actual operating data have demonstrated CO emission rates to be less than 6 ppm @ 15 % O₂. For Amendment 2 Duke Energy proposed the installation of DLN combustors to be deemed as BACT for CO and VOCs. The project was granted approval with a CO emission limit of 3.0 ppm based on an economic analysis using data from similar facilities.

Post-Combustion Controls

CO and VOC generated during combustion can be reacted with excess oxygen in the exhaust gas (oxidized), forming CO₂ and H₂O. There are two general post-combustion control methods: thermal oxidation and catalytic oxidation. Thermal oxidation uses a flame to incinerate the pollutants. Catalytic oxidation uses a catalyst to effect oxidation at the lower temperatures of the exhaust gases. In addition to oxidation, organic contaminants can be removed from gas streams using adsorption, condensation, or absorption technologies. However, these technologies are suited for gas streams containing much larger concentrations of hydrocarbons than found in the PGU exhaust streams.

- **Thermal Oxidation:** Thermal oxidation, also called direct-flame or direct-fired afterburners, uses an afterburner to combust the CO and VOC in the exhaust steam. Since the exhaust gas from CT units contains insufficient VOCs to sustain incineration, supplemental fuel is required in the afterburner. The gas is passed through the combustion zone of the flame at a typical temperature range of 1000°F to 1500°F. As with other combustion systems, thermal oxidation combustors must be designed to provide sufficient residence times at high temperatures with adequate turbulence for efficient combustion. The high combustion temperatures used in the thermal oxidation process produce more NO_x emissions than with catalytic oxidation. Thermal oxidation units are usually located prior to heat recovery process equipment to recover some of the energy released by the supplementary fuel. Organic contaminant removal efficiencies in excess of 95 percent can be achieved; however, emissions of CO₂ and NO_x increase. Although capital costs are relatively low, supplementary fuel costs drive operating costs up.
- **Catalytic Oxidation:** Catalytic oxidation also uses heat to oxidize CO and VOCs. This approach promotes the oxidation of CO to CO₂ without the use of reagents. Effective CO conversion occurs in the range of 700°F to 1200°F. The temperature of turbine exhaust gas is sufficient for catalytic oxidation without requiring supplemental fuel. The reduced residence time required for catalytic oxidation eliminates the need for an afterburner

combustion chamber, and a flame is not generated since the gas temperatures are below the auto-ignition temperature. Other forms of catalysts such as metal mesh or pellets are available but are not as effective as the monolithic form and introduce high pressure drops to the exhaust duct system.

Capital costs are about 40 percent higher than those of thermal oxidation, while operating costs are lower as supplementary fuel is not required. Catalysts generally require regeneration or cleaning every 3 to 6 years. However, commercial experience with oxidation catalysts installed on natural gas-fired combustion turbines reveals that catalyst cleaning or regeneration is seldom required. Because oxidation occurs on the catalyst sites, fouling of the sites by sulfur combustion products or significant amounts of particulates will reduce the catalyst removal efficiency.

- **Carbon Adsorption:** Carbon adsorption is a process by which organics are captured on the surface of granular solids. Common adsorbents include activated carbon, silica gel, and alumina. Adsorbents can be regenerated in place using steam or hot air, producing a secondary waste stream. The adsorption process is not effective, however, at temperatures below 100°F, and high concentrations of volatile organic compounds (>1,000 ppm) are required to achieve removal efficiencies on the order of 95 percent.
- **Condensation:** Condensation is another technology used to separate and remove organic contaminants from gas streams. This process involves reducing the temperature of the gas stream to below the saturation temperature of the contaminants, allowing the organics to condense, and collecting the liquid phase. Like the adsorption process, condensation is only effective for gases with high concentrations of organics, capable of achieving 95 percent removal for concentrations above 5,000 ppm. This process is used primarily for product recovery in chemical process lines.
- **Absorption:** Absorption is another removal technology developed for gas streams containing high concentrations of organics (>500 ppm). Water or organic liquids serve as the liquid absorbent used in packed towers, spray chambers, or venturi scrubbers. The gradient between the actual and the equilibrium concentration of the organics in the absorbent drives the migration of the organics in the gas stream to the absorbent liquid, and is typically enhanced at lower temperatures. The saturated liquid becomes a secondary waste stream.

Evaluation of Technical Feasibility

Both thermal and catalytic oxidation are considered technically feasible for the removal of CO and VOCs from the exhaust gas stream of a combustion turbine. The current permit states 3 ppm CO using DLN and SCR technology as a technically feasible control as well. The expected concentrations of organic compounds are too low for adsorption, condensation, or absorption to be considered technically feasible.

Control Technology Hierarchy

Both thermal and catalytic oxidation are considered technically feasible for the control of CO and VOCs emitted from a combustion turbine. Both technologies can achieve over 95 percent total organic contaminant removal efficiencies given optimum inlet concentrations, oxidation temperatures, and combustor or catalytic design. Catalysts are susceptible to poisoning or fouling by certain compounds in the exhaust gas which will reduce control efficiency. Sulfur compounds have been the most troublesome in the combustion of some fuel oils, solid fuels, and sewer gas. However the combustion products from burning clean fuels such as natural gas are not expected to affect the performance of an oxidation catalyst. Using an oxidation catalyst, 80 to 90 percent removal efficiencies can be achieved for CO removal from the combustion turbine's exhaust gas, and 30 to 90 percent for VOCs emitted from a combustion turbine. Catalyst vendors normally do not guarantee VOC removal rates. Specific hydrocarbon destruction efficiencies are unique to each installation as they are influenced by temperature, concentration, and exhaust gas composition; however, destruction efficiencies of 80 to 90 percent can be achieved for benzene and formaldehyde in gas turbine installations.

Comparable destruction efficiencies can be obtained using thermal oxidation, although there are environmental and economic disadvantages to thermal oxidation. Because the VOC concentration in turbine exhaust gas is too low to sustain combustion, supplemental fuel must be supplied, which increases costs and produces additional combustion products, including CO₂ and NO_x. In comparison to catalytic oxidation, thermal oxidation produces higher NO_x emissions as a combustion product since the oxidation (flame) temperature is much higher. Because of these environmental impacts, catalytic oxidation is ranked as the more effective control technology.

BACT Determination

The highest ranking control technology for CO and VOCs is catalytic oxidation. Because the conversion efficiency is tied directly to residence time, it can be increased by adding more catalyst material. Limitations to destruction efficiencies, therefore, become integral with the design of the exhaust system including space limitations. Economics ultimately limit the volume of catalytic material for a given project.

The next ranking control technology is DLN combustors.

- **Environmental Impacts:** Environmental impacts of using catalytic oxidation involve the disposal of the catalyst and additional products of combustion. The catalyst used to control CO in a gas turbine installation can become masked by compounds in the exhaust gas and may require thermal or chemical cleaning to expose the clogged reaction sites. Catalyst cleaning or regeneration, instead of disposal and replacement, minimizes waste associated with declining performance. As with other combustion processes, NO and other compounds containing nitrogen are converted to NO_x during catalytic oxidation. However, the conversion is minimal due to the low temperatures existing in the HRSG. Other environmental impacts associated with catalysts involve the oxidation of SO₂ to SO₃ resulting in H₂SO₄ mist and PM/PM₁₀. These conversions are also minimal because of the small amounts of sulfur found in natural gas. Because the SCR process injects ammonia into the exhaust stream, the oxidation catalyst is typically located upstream of

the SCR unit to avoid unnecessary NO_x generation. In summary, there are only minor environmental impacts associated with catalytic oxidation.

There are no significant environmental impacts associated with DLN combustors.

- **Energy Impacts:** The application of catalytic oxidation technology to a gas turbine will result in an increase in backpressure on the combustion turbine due to pressure drop across the catalyst bed. The increase in backpressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate.

There are no significant energy impacts associated with DLN combustors.

- **Economic Impacts:** For Amendment 2, Duke Energy submitted a BACT analysis focused on revising the CO emission limit for the Satsop CT Project. New emissions data impacted the cost analysis and supported the use of DLN combustors as BACT and an emission limit of 3 ppm for CO. Table 8 presents cost data as it relates to the current permit limit of 3 ppm.

Table 8
CO Catalyst verses DLN Economic Impacts

Emission Control Mechanism	CO Emission Concentration (ppm @ 15% O ₂)	CO Emission Rate kg/hr (lb/hr)	Tons of CO Removed Over Base	Cost Effectiveness (\$/Ton of CO Removed)
Dry Low NO _x (DLN) Combustor	3*	4.55 (10.0)	0	0
Low NO _x duct burner	3*	<u>2.39 (5.25)</u>		
Total emissions	3*	6.94 (15.25)		
DLN w/CO catalyst (with duct burner firing)	2	4.81 (10.6)	20.37	\$31,130

*Current emission limit in Amendment 2 permit.

**Cost data from Duke Energy submittal and attached to this BACT analysis as Appendix 1.

Selected BACT

Based on the excessive costs of catalytic oxidation, shown above, BACT for the Satsop CT Project is deemed to remain as proper combustion techniques and DLN combustors for both CO and VOC emissions. The proposed limits for CO and VOC emissions, as contained in the current permit, are shown in Table 9.

Table 9
Proposed BACT CO and VOC Emission Limits

Pollutant	Emissions (ppmvd) at 15% O₂	Emissions (lb/hr)
CO ^(a)	3.0	14.6
VOCs ^(b)	2.8	6.3

^(a)These emission limits apply to CT loads of 100%, 3-hr average.

^(b)These emission limits are carbon equivalents, 1-hr average.

Particulate Matter

Particulate matter (PM) emissions arise primarily from non-combustible metals present in trace quantities in liquid fuels. Other sources of particulate matter include condensable unburned organics and particles in the combustion air and ammonium bisulfate and ammonium sulfate compounds from the SCR/CO catalyst. These are included in PM emission estimates.

Available Control Technologies

This section describes control technologies available for the control of particulate matter emissions and their technical feasibility specific to a natural gas-fired combustion turbine. Table 10 presents the results of the RBLC search for particulate matter control technologies for projects similar to the proposed Satsop CT Project. Control methods can be grouped into two categories: (1) pre-combustion and combustion controls, and (2) post-combustion controls. As described below, pre-combustion and combustion controls include the use of clean-burning fuels and post-combustion controls include electrostatic precipitators and fabric filters.

Clean Fuels and Combustion Control

The use of clean burning fuels such as natural gas limits the presence of non-combustible metals in the fuel, consequently fewer particulates are formed during combustion. Efficient combustion, maintained by controlling (1) the air/fuel ratio and combustor staging sequences, and (2) the ambient conditions of the inlet air and plant loading requirements, ensure the minimum amount of condensable unburned organics are emitted. Combustion controls enable the combustion turbines to minimize fuel consumption as well, which in turn minimizes particulate emissions.

Post-Combustion Controls

- **Electrostatic precipitators and fabric filters** are used on solid fuel boilers and incinerators to remove large quantities of particulate matter and ash from the flue gas of solid fuel combustion. Electrostatic precipitators use a high voltage direct current corona to electrically charge particles in the gas stream. The suspended particles are attracted to

collecting electrodes of opposite polarity. These electrodes are typically plates suspended parallel with the gas flow. Particles are collected and disposed of by mechanically rapping the electrodes and dislodging the particles into the hoppers below.

- **Baghouses** are used to collect particulate matter by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags which are periodically shaken to release the particulates into hoppers.

Both technologies impose a significant pressure drop through the exhaust gas stream, requiring fans to blow the hot gases through the particulate control device and out the stack. Because particulate emissions from gas turbines are below the BACT control levels achievable using fabric filters and electrostatic precipitators (0.01 grains per standard cubic foot [gr/scf]), particulate control equipment has not been proposed for the back end of a combustion turbine.

Control Technology Hierarchy

The use of clean fuels and combustion control are technically feasible for particulate emissions from natural gas-fired combustion turbines. Particulate emissions from natural gas are much less than the levels of particulate control possible using control technologies such as electrostatic precipitators and fabric filters. The combination of clean burning fuels with combustion control is considered the most effective particulate control technology for natural gas-fired combustion turbines.

BACT Determination

Minimizing particulate emissions is achieved by operating on natural gas only and utilizing the most fuel-efficient combustion conditions.

Selected BACT

A review of the comparable gas turbine installations identifies combustion control and clean fuels as the only control technologies available for large combustion turbines. The proposed particulate matter emissions for the Satsop CT Project are representative of current BACT determinations. The proposed particulate matter emission limits, as contained in the current permit, are shown in Table 11.

Table 10
Pollution Control for Particulate Matter - Turbines

Facility	Emissions	Pollution Control	Basis
Bluewater Energy Center LLC	19.6 lb/hr	Exclusive Use of Natural Gas	BACT-PSD
BP Cherry Point Cogeneration	20.6 lb/hr	Natural Gas Fuel	BACT-PSD
Chehalis Generation Facility	379 lb/day		
COB Energy Facility, LLC	14.0 lb/hr	Good Combustion and Natural Gas	BACT-PSD
CPV Warren LLC	0.013 lb/MMBtu	Good Combustion and Natural Gas	-
Duke Energy Arlington Valley (AVEFII)	25.0 lb/hr	No Control Specified	BACT-PSD
Duke Energy Hanging Rock Energy Facility	23.3 lb/hr	No Control	BACT-PSD
Duke Energy Washington County LLC	28.0 lb/hr	No Control	BACT-PSD
Duke Energy Wythe LLC	23.7 lb/hr	Good Combustion Practices	BACT-PSD
El Dorado Energy, LLC	11.6 lb/hr	No Control Specified	LAER
Fairbault Energy Park	0.01 lb/MMBtu	Good Combustion Practices and Clean Fuel	BACT-PSD
Florida Power & Light Manatee Plant	No Value	Clean Fuels - 2 gr S/100 scf	BACT-PSD
Florida Power & Light Martin Plant	No Value	Clean Fuels - 2 gr S/100 scf	BACT-PSD
Forsyth Energy Plant	0.0210 lb/MMBtu	Good Combustion Practices and Clean Fuels	BACT-PSD
Hines Energy Complex	No Value	Good Combustion Practices and Clean Fuels	BACT-PSD
James City Energy Park	24.7 lb/hr	Good Combustion Practices and Clean Fuel	BACT-PSD
Kalkaska Generating LLC	38.0 lb/hr	Good Combustion Practices and Clean Fuels	BACT-PSD
Klamath Generation, LLC	0.0042 lb/MMBtu	Natural Gas <1 gr S/100 scf	BACT-PSD
Mankato Energy Center	0.0090 lb/MMBtu	Good Combustion Practices and Clean Fuels	BACT-PSD
McIntosh Combined Cycle Facility	0.0090 lb/MMBtu	Good Combustion Practices and Clean Fuels	BACT-PSD
Mint Farm Generation	23.3 lb/hr	Good Combustion Practices and Clean Fuels	
Mirant Wyandotte LLC	16.8 lb/hr	Good Combustion Practices and Natural Gas	BACT-PSD
Reliant Energy Choctaw County, LLC	20.59 lb/hr	No Control Specified	BACT-PSD
Sacramento MUD	9 lb/hr	Good Combustion Control	LAER
Salt River Project/Santan Gen. Plant	0.0100 lb/MMBtu		LAER
South Shore Power LLC	24.0 lb/hr	State of the Art Combustion Techniques and Use of Natural Gas	BACT-PSD
Sumas 2 Generation Facility	377 lb/day	Good Combustion; Low Sulfur Fuel	BACT-PSD
Wallula Power Project	0.0029 gr/dscf	Use of Natural Gas Only	LAER

Table 11
Proposed BACT PM₁₀ Emission Limit

Pollutant	Emissions (lb/day)
PM ₁₀	583.2 (front and back half)

^(a)This emission limit applies to loads $\geq 50\%$.

COOLING TOWERS

Wet cooling towers utilize air passage through the cooling water to cool the water for reuse. This direct contact between the cooling water and the air passing through the tower results in entrainment of some of the liquid water in the air stream. The entrained water is carried out of the tower as “drift” droplets. The drift droplets generally contain the same chemical impurities and additives as the water circulating through the tower. These impurities and additives can be converted to airborne emissions as the water in the drift droplets evaporate and leaves fine particulate matter formed by crystallization of dissolved solids.

As part of certain processes, water is used to remove heat from hydrocarbon-carrying streams. Equipment (e.g., leaking heat exchangers) can introduce small quantities of VOCs into the cooling water stream. These VOCs are then emitted from the cooling towers as a result of the direct contact air passage through the towers. The Satsop CT Project, however, does not have any hydrocarbon-carrying streams. Consequently, no quantifiable VOC emissions are expected from this source. Thus, the BACT analysis for cooling towers focuses on particulate matter emissions only.

A review of EPA’s RBLC database and current Washington state permits was conducted for cooling tower information. The review shows the best control technique for PM₁₀ emissions from cooling towers continues to be drift eliminators, as shown in Table 12.

Table 12
Pollution Control Cooling Towers

Facility	Emissions	Pollution Control	Basis
BP Cherry Point Cogeneration	7.2 tpy	0.001% drift	BACT-PSD
Duke Energy Hanging Rock Energy Facility	2.6 lb/hr	Drift Eliminators	BACT-PSD
Duke Energy Washington County LLC	2.08 lb/hr	No Control Specified	BACT-PSD
Forsyth Energy Plant	0.007 lb/hr	No Control Specified	BACT-PSD
Mint Farm Generation	1.08 tpy	Drift Eliminators	
Wallula Power Project	3.7 lb/hr	Water Pretreatment and 0.0005% Drift Rate	LAER

Drift eliminators are usually incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower. The drift eliminators used in cooling towers rely on the inertial separation caused by directional changes in the airflow while passing through the eliminators. Types of drift eliminator configurations include herringbone (blade-type), wave form, and cellular (or honeycomb) designs. The cellular units generally are the most efficient. Drift eliminators may include various materials, such as ceramics, fiber reinforced cement, fiberglass, metal, plastic, and wood installed or formed into closely spaced slats, sheets, honeycomb assemblies, or tiles. The materials may include other features, such as corrugations and water removal channels, to enhance the drift removal further.

Two-stage, low-drift eliminators (0.001 percent of flow) remain proposed as BACT for the cooling tower.

AUXILIARY BOILER

Air emissions from natural gas-fired boilers include NO_x, CO, PM₁₀, SO₂, and VOCs. No significant control technologies have been implemented for boilers since the last BACT review. Consequently, the following analysis is still valid and it is proposed that BACT for the boilers remain as dictated in the current permit..

Nitrogen Oxides

This section addresses the available control alternatives for NO_x emissions.

Available Control Technologies

The available NO_x control technologies for natural gas-fired boilers are briefly described below.

- **Low NO_x Burners:** Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. Utilizing low NO_x burners is a combustion control method that reduces the peak temperature in the combustion zone, reduces the gas residence time in the high-temperature zone, and provides a rich fuel/air ratio in the primary flame zone. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emissions levels) have been observed with low NO_x burners.
- **Flue Gas Recirculation (FGR):** In a FGR system, a portion of the flue gas is recycled from the stack to the primary combustion zone. Upon entering the primary combustion zone, the re-circulated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. Primarily, the re-circulated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone.

The amount of re-circulated flue gas is a key operating parameter influencing NO_x emission rates for these systems. FGR systems are capable of reducing NO_x emissions by 49 to 68 percent.

A FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NO_x burners and FGR are used in combination, these techniques are capable of reducing NO_x emissions by 60 to 90 percent.

- **Staged Air/Fuel Combustion:** Staged air combustion, or off-stoichiometric combustion, combusts the fuel in two or more steps. A percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. The total amount of combustion air fed to the boiler remains unchanged. Initially, fuel is combusted in a primary, fuel-rich, combustion zone. Combustion is completed at lower temperatures in a secondary, fuel-lean, combustion zone. The sub-stoichiometric oxygen introduced with the primary combustion air into the high temperature, fuel-rich zone reduces fuel and thermal NO_x formation. Combustion in the secondary zone is conducted at a lower temperature, reducing thermal NO_x formation. In staged combustion, the degree of staging is a key operating parameter influencing NO_x emission rates. Staged combustion can reduce emissions by 5 to 20 percent.

Evaluation of Technical Feasibility

Each of the three NO_x control technologies described above are considered technically feasible with respect to the auxiliary boiler proposed for the Satsop CT Project. Combining FGR with low NO_x burners provides the most effective control of NO_x emissions. The technology ranking from highest (most effective) to lowest for the auxiliary boilers proposed for the Satsop CT Project is as follows:

1. FGR with low NO_x burners
2. Low-NO_x burners
3. FGR
4. Staged air/fuel combustion

BACT Determination

A cost-effectiveness analysis was not performed since the most efficient control technology identified (FGR with low-NO_x burners) is still proposed to be installed on the auxiliary boiler for the Satsop CT Project.

Selected BACT

A combination of FGR and low-NO_x burners has been selected as the NO_x emissions control technology for the auxiliary boiler. The current and re-proposed BACT emission limit for NO_x is shown in Table 13.

Table 13
Proposed BACT NO_x Emission Limits for the Auxiliary Boiler^(a)

Pollutant	Emissions (ppmvd) at 15% O₂	Emissions (lb/MMBtu)	Emissions (lb/hr)
NO _x	30	0.035	1.03

^(a)Based on 100% load.

Carbon Monoxide, Particulate Matter, Sulfur Dioxide, and Volatile Organic Compounds

The RBLC search identified the use of natural gas as an exclusive fuel in combination with good combustion practices as representing the most stringent control available for CO, PM₁₀, SO₂, and VOC. No post-combustion controls for these pollutants were identified during the review. Emissions limits for these pollutants are proposed to remain as dictated in the current permit.

DIESEL EMERGENCY GENERATOR AND FIRE PUMP

Air emissions from diesel internal combustion (IC) generators and engines include NO_x, CO, PM₁₀, SO₂, and VOCs. No significant control technologies have been implemented for emergency diesel generators or diesel fire pumps since the last BACT review. Consequently, the following analysis is still valid and it is proposed that BACT for the diesel generator and fire pump remain as dictated in the current permit.

Nitrogen Oxides

The formation of nitrogen oxides is the result of thermal oxidation of diatomic nitrogen in the combustion chamber. The rate of formation is dependent upon combustion temperature, residence time of combustion products at high temperatures, and the availability of oxygen in the flame zone of a combustion turbine generator. This section addresses the available control alternatives for NO_x emissions.

Available Control Technologies

Control technologies for NO_x emissions can be classified as combustion modifications or post-combustion controls. The available NO_x control technologies for natural gas-fired combustion turbines are briefly described below.

- **Turbocharging/Aftercooling:** Turbocharging and aftercooling lowers NO_x emissions by running the turbocharged intake air past a heat exchanger. This lowers the temperature of combustion, resulting in less NO_x formation. Most new stationary diesel engines are equipped with a turbocharger and aftercooling system.
- **Fuel Injection Timing Retard and Variable Fuel Injection Timing Retard:** Fuel injection timing retard (FITR) lowers NO_x emissions by moving the ignition event to

later in the power stroke. Because the combustion chamber volume is greater at the time of ignition, the peak flame temperature will be reduced, thus reducing NO_x formation. Variable FITR (VFITR) adjusts the timing continuously for optimum emission reduction. Most modern computer controlled fuel injection systems implement VFITR.

Proposed BACT for NO_x is VFITR and turbocharging/aftercooling to meet 2002 new engine emission standards applicable to off-road mobile devices, but installed in a stationary source as dictated in the current permit.

Sulfur Dioxide

SO₂ emissions from diesel IC generators and fire pumps are a function of the sulfur content of the fuel. Virtually all fuel sulfur is converted to SO₂. The RBLC listed no SO₂ emission controls for emergency diesel IC engines or fire pumps other than fuel sulfur specifications. Current on-road No. 2 fuel oil contains no greater than 0.05 percent sulfur. Proposed BACT for SO₂ for the emergency diesel generator and fire pump is on-road specification diesel fuel as dictated in the current permit.

Carbon Monoxide and Volatile Organic Compounds

CO is a product of incomplete combustion, where oxygen is not present in sufficient quantities to fully oxidize the fuel. In addition, CO emission levels are a direct function of the air/fuel ratio. Combustion inefficiencies introduced by combustion modifications for NO_x control increase the generation of CO. VOC emissions are also products of incomplete combustion. Some VOCs are involved in the process of ozone formation.

The RBLC does not list any available control technologies for emergency use diesel generators or fire pumps. For non-emergency use an oxidation catalyst can be used to reduce both CO and VOCs. However, due to the nature of emergency power-generation, oxidation catalysts are not demonstrated technologies for emergency use. Proposed BACT is no control.

Particulate Matter

PM₁₀ emissions arise primarily from non-combustible metals present in trace quantities in liquid fuels. Other sources of PM₁₀ include condensable unburned organics and particles in the combustion air.

The RBLC search for particulate matter control technologies for emergency use diesel generators and fire pumps produces no listing of available particulate matter controls. For non-emergency use, combustion controls include the use of clean-burning fuels and post-combustion controls include fabric filters. However, due to the nature of emergency power-generation, fabric filters are not demonstrated technologies for emergency use. Proposed BACT for Particulate Matter is using clean-burning fuels.

TOXIC AIR POLLUTANTS

Washington Administration Code (WAC) 173-460 requires that all sources that apply for a Notice of Construction (NOC), and may potentially increase emissions of regulated toxic air pollutants (TAPs), conduct a best available control technology for toxics (T-BACT) analysis. The T-BACT analysis ensures that the best available technology is utilized to control TAP emissions. Therefore, a T-BACT analysis was conducted for the Satsop CT Project emission sources.

The T-BACT requirements apply to all applicable stationary sources at the facility. Consequently, for the Satsop CT Project the following sources will be included in the T-BACT analysis:

- Two combined cycle combustion turbines
- One auxiliary natural gas-fired boiler
- One forced draft cooling tower system
- One emergency backup diesel generator
- One fire pump

Due to the similarities between a BACT and T-BACT analysis, a review of all traditional BACT resources was conducted to identify potential T-BACT emission information. Although minimal supporting material was discovered, information in the Factor Information Retrieval (FIRE) Data System (Version 6.23) provided some pollutant-by-pollutant emission data in support of past T-BACT determinations. The FIRE database is a management system containing EPA's recommended emission estimation factors for criteria and hazardous air pollutants. FIRE includes information about industries and their emitting processes, the chemicals emitted, and the emission factors themselves.

FIRE listed several regulated toxic air pollutants of interest, and identified the pollution control equipment that would have impacts on the emissions. Although the pollution control equipment reviewed was not installed to reduce the TAP emissions, it did reveal that in some cases the TAP emissions were also reduced, and in other cases the TAP emissions actually increased. Table 14 summarizes the information obtained from FIRE.

As shown in Table 14, several of the TAPs emission rates were reduced by pollution control equipment, although the pollution control equipment was not installed to reduce the TAP emissions. The equipment was originally installed to reduce other targeted pollutants, e.g. nitrogen oxides, but due to the nature of the TAP, some TAP removal resulted.

Gas Turbines

There are no specific controls for TAP emissions on existing turbines. The control technologies typically installed on turbines are utilized to control other non-TAP pollutants, such as NO_x, or CO. These controls in some cases decrease certain TAP emissions while increasing other TAP emissions. For instance, TAP emission reductions occur when control technologies such as afterburners, CO catalytic reduction, and SCR systems are employed. Reductions in the range of

47 percent to 97 percent have been reported for TAP emissions such as acetaldehyde and formaldehyde. Although there is very limited data regarding the reduction of other TAP emissions, it can be anticipated that other TAP emissions of similar characteristics to acetaldehyde and formaldehyde would also result in emission reductions. As noted above, some TAP emissions may actually increase as a result of certain control technologies. Namely, emissions of naphthalene and ammonia will increase, if using ammonia injection as part of the SCR technology. (Ammonia emissions are a result of ammonia slip, or carryover, when ammonia is injected.)

Additional TAP emission reductions will occur with the exclusive use of natural gas. Natural gas is a “cleaner” fuel as compared to fuel oil, i.e., less air pollutants are emitted when burning natural gas. Consequently, the use of natural gas is considered T-BACT.

Therefore, based on the T-BACT technology review, the proposed T-BACT for the gas turbines is no control, besides the use of natural gas. Note, that the proposed gas turbines will have SCR for the control of non-TAP pollutants. As noted above, these technologies will result in some reduction of selected TAPs but should not be considered as T-BACT for the TAPs; these technologies are beyond established T-BACT thresholds.

Duct Burners

The turbine duct-firing feature is rated at 505 MMBtu per hour. Therefore, the associated air pollutant emissions would be similar to natural gas fired boilers rated greater than 100 MMBtu per hour. No data was found for turbine duct-firing processes, however, FIRE did provide information regarding TAP emissions from natural gas fired boilers greater than 100 MMBtu per hour. This information was then used to characterize and evaluate the TAP emissions from the duct burners.

Table 14 shows three TAPs that were affected by the installed pollution control equipment. The data shows that only one technology resulted in a reduction of emissions, namely formaldehyde. Formaldehyde emissions were reduced when flue gas recirculation was employed. This technology is not available for gas turbines. Of the two remaining TAPs, both resulted in emission increases when the control equipment was utilized. Ammonia emissions increased when SCR was applied, and mercury emissions increased when a scrubber was used. Consequently, these control technologies would not be recommended as a method to reduce these TAP emissions.

Table 14
TAP Emission Control Technologies

Emission Source	Toxic Air Pollutant (TAP)	Uncontrolled Emission Rate	Controlled Emission Rate	Percent Reduction or (Increase)	Control Technology
Natural Gas Fired Turbine	Acetaldehyde	4.00×10^{-5} lb/MMcf	2.13×10^{-5} lb/MMcf	47%	Afterburner
	Acetaldehyde	4.00×10^{-5} lb/MMcf	4.29×10^{-6} lb/MMcf	89%	SCR
	Benzene	1.20×10^{-5} lb/MMBtu	9.10×10^{-7} lb/MMBtu	92%	Catalytic reduction
	Formaldehyde	7.10×10^{-4} lb/MMBtu	2.00×10^{-5} lb/MMBtu	97%	Catalytic reduction
	Naphthalene	1.30×10^{-6} lb/MMBtu	1.03×10^{-5} lb/MMBtu	(691%)	SCR
Natural Gas Fired Boiler 10 - 100 MMBtu/hr	Ammonia	4.90×10^{-1} lb/MMcf	9.10×10^0 lb/MMcf	(1757%)	SNCR
Natural Gas Fired Boiler >100 MMBtu/hr (Duct Burner)	Ammonia	3.20×10^0 lb/MMcf	1.80×10^1 lb/MMcf	(463%)	SNCR
		3.20×10^0 lb/MMcf	9.10×10^0 lb/MMcf	(184%)	SCR
	Formaldehyde	7.50×10^{-2} lb/MMcf	3.95×10^{-5} lb/MMBtu	46%	Flue Gas Recirculation
	Mercury	2.60×10^{-4} lb/MMcf	2.27×10^{-6} lb/MMBtu	(791%)	Wet Scrubber

Auxiliary Boiler

The auxiliary boiler is rated at 29.3 MMBtu per hour. Therefore, emission data from FIRE version 6.23 for boilers rated in the 10 to 100 MMBtu per hour range was used to characterize the toxic air pollutants. As shown in Table 14, the FIRE data only provided toxic emission data for ammonia emissions. Ammonia emissions resulted in an increase due to the use of SCR.

There were no other references or information regarding toxic emission data for the auxiliary boiler. However, similar to the turbine generators, the exclusive use of natural gas will maintain the toxic air emissions at a minimum. Therefore, the use of natural gas is considered T-BACT for the auxiliary boiler.

Cooling Tower

There are no TAP emissions data for water cooling towers. However, as found in AP-42, TAP emissions would be related to the chemicals impurities that are found in the water (USEPA 1985b, Section 13.4 regarding "Wet Cooling Towers"). Because there are no chemical additives, such as biocides being added, and no carryover chemicals from the turbine condensers, there

should not be any TAP emissions from the cooling tower. Therefore, T-BACT for the water cooling tower is no control.

Diesel Emergency Generator and Fire Pump

There are no specific controls for TAP emissions on emergency backup diesel generator or fire pump. Proposed T-BACT is an annual limit of 500 hours of operations for the diesel generator.

A summary of the proposed T-BACT for the sources at the Satsop CT Project are summarized in Table 15 below.

Table 15
Proposed T-BACT

Emission Source	Proposed T-BACT
Gas Turbine	Exclusive use of natural gas.
Turbine Duct Firing	Exclusive use of natural gas.
Auxiliary Boiler	Exclusive use of natural gas.
Water Cooling Tower	No TAPs; therefore, no control.
Diesel Emergency Generator	500 hours per year operational limit.
Diesel Fire Pump	No control

Sulfuric Acid Mist, Ammonia, and Opacity

Table 16 lists the emission limits found in some of the RBLC entries for sulfuric acid mist, ammonia, and opacity.

Table 16
Pollution Control for Other Constituents

Facility	Sulfuric Acid Mist	Ammonia	Opacity
Bluewater Energy Center LLC	8.2 lb/hr 0.008 gr S/scf	10.0 ppm	
BP Cherry Point Cogeneration	2.8 lb/hr	5 ppm	5%
Chehalis Generation Facility	2.0 lb/hr	10 ppm	10%
COB Energy Facility, LLC		5 ppm	20%
CPV Warren LLC	0.0005 lb/MMBtu		
Duke Energy Hanging Rock Energy Facility	2.2 lb/hr	37.8 lb/hr	10%
Duke Energy Washington County LLC	2.2 lb/hr	34.6 lb/hr	10%
El Dorado Energy, LLC		10.0 ppm	
Florida Power & Light Manatee Plant	2 gr S/100 scf	5.0 ppm	10%
Florida Power & Light Martin Plant		5.0 ppm	10%
Hines Energy Complex	Low Sulfur Fuels	5.0 ppm	10%
Kalkaska Generating LLC		10.0 ppm	
Klamath Generation, LLC		10.0 ppm	
Mankato Energy Center	0.008 gr S/scf		
McIntosh Combined Cycle Facility			10%
Mint Farm Generation		10 ppm	5%
Mirant Wyandotte LLC	12.3 tpy	10.0 ppm	
South Shore Power LLC		3.3 tpy	
Sumas 2 Generation Facility	39 lb/day	5 ppm	10%
Wallula Power Project	0.0002 gr/dscf	5.0 ppm	5%

Table 17 presents the current limits in the permit for the Satsop CT Project. It is proposed that these limits remain as BACT.

Table 17
Other BACT Emission Limits

Pollutant	Emission Limit
Sulfuric Acid Mist	2.17 lb/hr
Ammonia	5 ppm slip
Opacity	5 %

SUMMARY

The current limits in the permit for the Satsop CT Project still represent BACT and T-BACT. No new technologies or techniques for pollution control have proven effective since the last BACT determination, completed in 2004. This BACT analysis supports extending the permit another 18 months.

Appendix 1

Cost Data for Catalytic Oxidation*

Capital Costs per Turbine

	Items	Value	Basis
Purchased Equipment	Equipment costs	\$ 1,241,875	Vendor Quote = A
	Instruments	\$ 124,200	0.10*A
	Sales tax	\$ 86,900	0.07*A
	Freight	\$ 62,100	0.05*A
	Total Equipment costs	\$1,515,075	B = 1.22*A
Direct Installation Cost	Foundations and Supports	\$ 121,000	0.08*B
	Handling and Erecting	\$ 212,100	0.14*B
	Electrical	\$ 60,600	0.04*B
	Piping	\$ 30,300	0.01*B
	Insulation	\$ 15,200	0.01*B
	Painting	\$ 15,200	0.01*B
	Total installation costs	\$ 454,600	0.30*B
Total Direct Costs		\$ 1,969,700	
Indirect costs (installation)	Engineering	\$151,500	0.10*B
	Construction/field expense	\$75,800	0.05*B
	Contractor fees	\$151,500	0.10*B
	Start-up	\$30,000	0.02*B
	Performance tests	\$15,200	0.01*B
	Contingencies	\$45,500	0.03*B
	Total construction	\$ 469,800	0.31*B
Total Capital Investment Costs		\$2,439,500	

Operating Costs per Turbine

Item	Value	Basis	Source
Electricity	3.0	Pressure Drop	Vendor
Pressure Drop (in. WC)	180,000		
Power Output of Turbine (kW)	0.3%	0.1% per I in.	Vendor
Power Loss Due to Pressure drop (kW)	540		
Unit Cost (\$/kWh)	\$0.045		Estimate
Cost (\$/yr) (based on 4,000 hours)	\$97,200		
Operating Labor	\$19,110		OAQPS
Supervisory Labor	\$2,870		OAQPS
Maintenance			
Labor	0.5	½ hr per shift	OAQPS
Analyzer labor	0.0		
Catalyst replacement labor	0.1	40 hr./yr	
Unit cost(\$/hr)	\$35.00		
Labor Costs (\$/yr)	\$24,230		
Material Costs (\$/yr)	\$24,230		OAQPS
Total Costs (\$/yr)	\$48,460		
Catalyst Replacement			
Catalyst Costs	\$359,000	Catalyst	Vendor
Annual Cost (\$/yr) (3 year life)	\$139,800		OAQPS
Indirect Annual Costs			
Overhead	\$42,260		OAQPS
Administrative	\$48,790		OAQPS
Property Tax	\$24,400		OAQPS
Insurance	\$24,400		OAQPS
Capital Recovery	\$296,220		OAQPS
Total Indirect (\$/yr)	\$414,070		OAQPS
Total Annualized Cost (\$/yr)	\$634,030		

*Cost data and table presented in support of Amendment 2 permit revisions in 2004 by Duke Energy.